The Economics of Different Generation Technologies for Frequency Response Provision

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Abstract

The provision of reserve generation is an essential part of maintaining a reliable electricity system and has become an increasingly difficult task with the growing contribution from variable energy sources. Ensuring the cost of balancing supply and demand is minimised is an important aspect, requiring an understanding of how generator costs vary depending on their operation. This paper considers the cost of part loading different generator types, providing a cost breakdown and description of the Levelised Cost of Electricity method of analysing generator costs. This delivers cost-loading level curves for the generator types with the largest contribution to the UK generation portfolio which can be used to perform economic optimisations for generator scheduling. The holding payment for provision of frequency response, an aspect of maintaining balance between generation and demand, is separated by generator type and compared with the calculated part loading costs. To demonstrate the effect on system costs the Winter peak and Summer trough in 2016 and the Future Energy Scenarios in 2020 are considered with maximum and minimum generator numbers connected. Provision of sufficient generation to meet demand and reserves are optimised to reduce costs in each scenario.

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[1] The short version of the paper was presented at ICAE2017, Aug 21-24, Cardiff, UK. This paper is a substantial extension of the short version of the conference paper.

Keywords: balancing services; frequency response; generator part loading; power generation; power system economics

1. Introduction

The cost of electricity provision combines several aspects; including infrastructure, production and ensuring a secure supply. As the contribution from variable energy resources (VER) increases ensuring a secure supply will become a bigger challenge, requiring more flexible generators to guarantee there is sufficient reserve available on the system [1, 2, 3].

As demand fluctuates supply must follow, which requires reserve available for unpredicted changes. Balancing services have cost the UK £62.49m and £71.10m in January and February 2017 respectively [4], with £24.7m and £20.8m spent on ensuring reserves could respond to unanticipated demand changes. This response occurs over a variety of time frames; frequency response over the first few seconds whilst short term operating reserve responds over several minutes. These reserve services require head room available to respond and the reserve payment must cover the loss of income generators experience through reducing their output, which is a focus for this paper.

In recent years a move away from traditional thermal generators providing mandatory frequency response towards commercial frequency response providers has occured. Energy storage is potentially competitive in the commercial frequency response markets in relation to batteries [5], community energy storage [6], electric vehicles [7] and the utilisation of storage alongside wind farms increases their frequency response and inertia capabilities [8, 9, 10]. Batteries do not possess sufficient capacity currently to cover reserve requirements but energy storage, in the form of pumped storage, will be considered in this paper. In contrast demand side response theoretically has capacity equal to the entire system but control is currently limited, with only large industrial and commercial loads responding [11]. With the introduction of smart grids [12], usage of responsive refrigerators [13] or alternative frequency control methods [14] this may be an option in the future.

The provision of flexibility by VER is limited, VER is considered the cause of imbalances rather than a source of ancillary services [10, 15, 16] and cost allocation to alleviate this problem is under consideration [3]. However numerous methods have been proposed to utilise this resource [10, 17, 18, 19] which will become an increasingly important reserve to exploit in the future, with increased environmental costs and penalty payments associated with emissions. This paper will only consider wind providing reserve through a part loading technique, rather than the incorporation of storage or solar, as this is the only large scale VER reserve method currently available in the UK system.

Previous research into economic reserve provision has focused on ensuring there will be sufficient flexible generation available with an increase in VER [1, 18, 20], optimising the future generation portfolio and predicting the costs associated with this new generation mix [21, 22]. These papers consider a variety of costs but ignore the cost incurred by part loading the generator initially. This cost is a major contributor to the reserve payment, varying considerably between different generators and loading levels.

In this paper we provide cost curves for part loading the largest contributors in the UK generation portfolio. To demonstrate the effect this has on the total system cost scenarios with maximum and minimum numbers of part loaded generators at the Winter peak and Summer trough in 2016 and 2020 Future Energy Scenarios (FES) [2] are quantified. These scenarios also consider frequency response reserve requirements and provides a method for optimising generators to meet demand and reserve requirements based on specified generation mixes. This method can be utilised to ensure system costs are minimised whilst maintaining safe and secure operation.

Section 2 explains the main contributors to part loading costs, presents the cost curves for different generator types and considers the change in generation mix over the last few years in the UK. In section 3 typical holding payments for mandatory frequency response in the UK are presented and compared with the cost incurred from part loading generators. Section 4 considers the total system costs in both 2016 and 2020 scenarios with maximum, minimum and optimised numbers of generators to meet demand and reserve requirements. The conclusion to the paper is presented in section 5.

2. Part loading cost

There are multiple contributors to the cost of electricity production, with different cost aspects dominating each generator [23]. Past costing analysis focused on capital, operation and maintenance (O&M) and fuel costs to provide estimations for electricity production [24, 25]. There are also assessments of the startup costs [1] which must be considered when looking at the overall system, but are not relevant for the part loading of individual generators.

The capital cost is a fixed value, including the costs from the planning stage of a new generating plant to the point of commercial operation [26]. It is a major component for nuclear power stations, contributing 60-70% of the overall cost, due to their significant construction time, 8.63 years in the UK [25, 27]. However coal and combined cycle gas turbine (CCGT) plants, 1-2 years [28] and 2.5 years construction time respectively, have 30-40% of their total cost contributed by their capital investment [26]. Renewable generators also have high capital costs depending on the site chosen [29]. The typical capital cost for several generator types in the UK can be seen in fig. 1.

The O&M cost can be split into variable and fixed costs: Variable O&M costs change in relation to electricity production, such as replacement of parts, whilst fixed remain constant, such as wages for plant personnel [25, 30]. The fuel cost can be considered a variable O&M cost. Coal and CCGT plants have a significant contribution, 50-65% [26, 31], from the price of fuel whilst nuclear is relatively low and stable, 5-10% of the overall cost. Renewable generators, such as wind, have neglible fuel costs, as shown in fig. 1, but the maintenance, in particular for offshore wind farms, is substantial due to the challenges associated with their location. Another operational cost is the carbon price, paid by fossil fuel plants to encourage the reduction of CO_2 emissions. In the UK in 2017 the carbon price is £18 per tonne of CO_2 released [32].

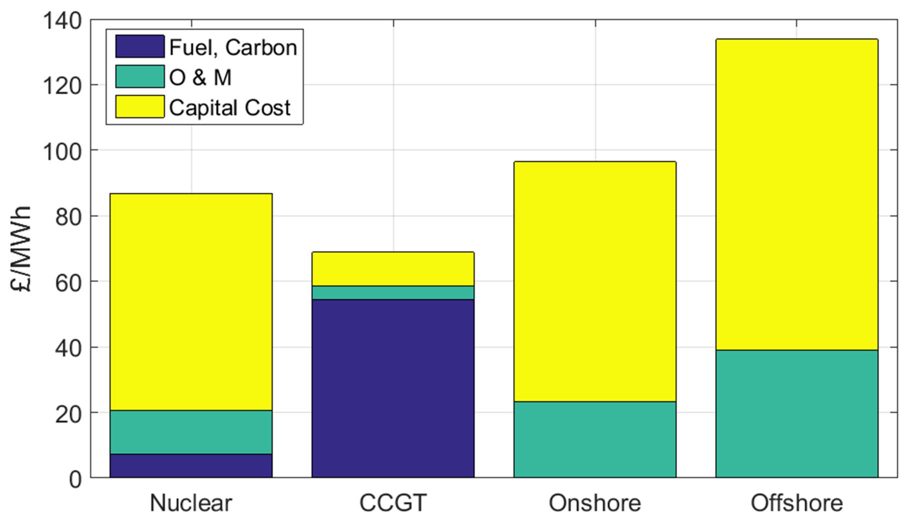

Figure 1: Cost breakdown for different generator types [26, 33, 34]

The efficiency of a generating unit is plant specific and linked with the conversion of fuel into useful energy [33]. It changes over the operation of the plant dependent on several factors, including the loading level and maintenance.

In this paper the capital, O&M, fuel and carbon costs are considered for each generating type, with the efficiency linked to fuel usage where appropriate.

2.1. Cost quantifying method

Levelised Cost of Electricity (LCOE) is a tool used to assess and compare options with regards to various costs on a common base [35, 36, 37]. It can consider a wide range of costs but typically considers the planning, construction, operation and the decommissioning stages of a generating plant for a lifetime output power. This is used to choose between different design or investment options, such as the sizing of PV panels for a microgrid [35] or offshore wind turbine design changes [36, 37].

An alternative tool is marginal pricing, used to quantify the cost to produce an extra unit of electricity by considering the additional operational costs this would induce [38]. Marginal pricing is commonly used in market applications, where system marginal cost is used to refund market participants for their services or as an aspect of generator scheduling [39, 40]. The lack of a common base to compare between different generators makes it undesirable for this particular application.

Life-Cycle Cost Assessment can be used as a costing method for generator options [23, 25, 41] taking in to account the various costs throughout the lifetime of the generation plant. However this method does not provide a common base, typically providing a cost per generator [25], and often incorporates environmental costs into the analysis [23].

To consider different generator types and the effect loading levels have on their lifetime cost equation 1 has been formed based on the LCOE tool. It details how the different cost contributors are combined to find the total £/MWh cost each generator must charge to recover their investment depending on the average lifetime loading level.

$$\begin{aligned} Cost_{Loading} = C_{Capital} \times \frac{E_{Expectedlifetime}}{E_{Actuallifetime}} \\ + C_{O\&M} \times \frac{E_{Expectedlifetime}}{E_{Actuallifetime}} \\ + C_{Fuel} \times \frac{1}{\eta} + C_{Carbon} \end{aligned} \tag{1}$$

where $Cost_{Loading}$ is the cost of electricity production at a chosen average loading level, $C_{Capital}$ is the generator capital cost, $C_{O\&M}$ is the generator operation and maintenance cost, C_{Fuel} is the fuel cost and C_{Carbon} is the carbon price which are all measured in £/MWh. $E_{Expectedlifetime}$ is the total generator output expected over the plant lifetime and $E_{Actuallifetime}$ is the total generator output achieved over the plant lifetime in MWhs, whilst η is the percentage generator efficiency at the chosen loading level.

2.2. Generation types

Each generator has restrictions on their operation but there are average values for each generation type which can be used.

Table 1: Generation loading levels as a percentage of rated capacity

Generation type	Designed Minimum Operating Level (DMOL) (%) [1, 24, 42]	Average UK loading level (%) [43, 34]	Availability factor (%) [44, 45]
Coal	50	58	85
CCGT	40	72	99
Nuclear (PWR)	50	74	100
Biomass	50	56	83
Wind	10	28 (onshore)	44 (onshore)
		38 (offshore)	40 (offshore)
Pumped Storage	-	41	90

The average loading level of generators is the yearly output of the generator divided by the total possible output assuming constant operation at rated capacity [43, 34]. This will not be the level each plant is constantly operating at but the average level across the lifetime of the plant will dictate the price.

Generators are disconnected for maintenance or under limited operation, reducing their availability factor [44, 45]. A generator with a low availability factor may be able to operate part loaded, such as coal power plants limited by the Large Combustion Plant Directive (LCPD) [46], or can only operate during certain weather conditions, such as wind power.

2.2.1. Coal

Shown in fig. 2 the cost per MWh of electricity generated for coal at 100% load is estimated to be around £57/MWh. The cost increased as the loading level of the unit decreases towards its Designed Minimum Operating Level (DMOL) of 50% of the rated capacity with a cost of around £117/MWh, over double the cost per MWh of the plant operating at full load. Whilst operating above 75% the £/MWh remains fairly consistent, implying the power station can run partially loaded without significant cost implications above this level.

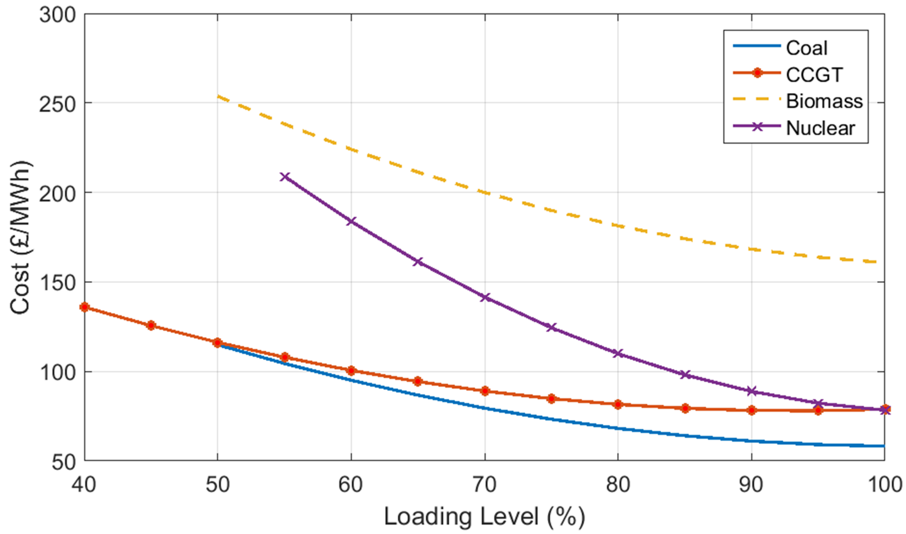

Figure 2: Change in the cost of operation of thermal generators as the average loading level varies [34]

2.2.2. Combined Cycle Gas Turbine (CCGT)

As shown in fig. 2 the cost remains fairly consistent, as with coal, above the 75% loading level but experiences a significant increase in cost as it approaches its DMOL, £76/MWh at 100% to £141/MWh at 40%. The considerable contribution in cost based on the fuel makes the required £/MWh to return the investment dependent on gas prices but an increase in gas prices will cause a flattening of the curve encouraging part loading of CCGTs over other generators.

2.2.3. Nuclear

Nuclear is considered a base load plant, often running fully loaded for extended periods of time. All but 1 of the 15 currently operational nuclear plants in the UK are Advanced Gas-cooled Reactors (AGR), with the remaining plant a Pressurised Water Reactor (PWR) [47]. The loading curve for nuclear power is based on an AGR design, which were permitted a lifetime exemption from providing ancillary services. It can be seen that there is a sharp increase in cost below 90%, doubling from £90/MWh at 90% to £181/MWh at 60%.

New nuclear in the UK is currently under construction with both PWR and Boiling Water Reactor (BWR) designs, but these are still not designed to operate in a part loaded state [47]. Although they will not have exactly the same prices as AGRs they do experience similarly high capital costs and require the same fuel [34] which allows AGRs to be used as a comparison point for all nuclear reactor types.

2.2.4. Biomass

Biomass is a relatively unused generation type in the UK, with the conversions from coal to biomass the only large scale units as of 2016 [28] but is gaining popularity in small scale [2]. It has a higher overall cost than the other thermal generators but follows the same basic pattern, a relatively consistent cost above 75% before a steady increase in cost approaching the DMOL. Although it is an expensive alternative to coal and CCGTs there is an option to part load without significant cost implications.

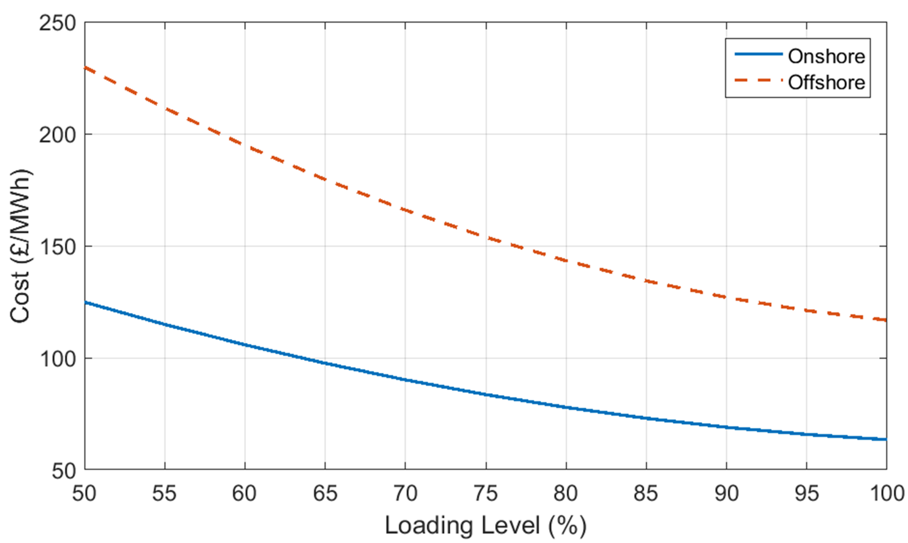

Figure 3: Change in the cost of operation of wind farms as the average loading level varies [34]

2.2.5. *Wind*

Wind is a VER making it difficult to compare directly with other generators. Changes in the weather, wind speed either above or below their operational window, and an inability to perform maintenance on wind turbines in hard to access locations will render them temporarily unavailable. To overcome this issue the availability factor is used, as shown in equation 2, to ensure only the periods of time wind generation is available are considered. The availability factors of other generation types are not used in this analysis as they are available more than 80% of the time and can choose when they will be offline to perform maintenance.

$$Cost_{Availabiltiy} = Cost_{Loading} \times \frac{LoadingLevel}{AvailabilityFactor} \tag{2}$$

where $Cost_{Availabiltiy}$ is the cost of electricity production assuming 100% availability and $Cost_{Loading}$ is the cost of electricity production at chosen average loading level in £/MWh. The $LoadingLevel$ is the average loading level and the $AvailabilityFactor$ is the availability of the generator.

Without the possibility of fuel savings, as seen with the thermal generators, both onshore and offshore wind generators experience an immediate increase in costs as the loading level decreases. There is still a relatively gradual slope above 80%, but it is less pronounced than that seen by coal and CCGT plants.

2.2.6. *Pumped Storage*

Pumped storage has been a part of the UK generation mix for many years providing balancing services rather than wholesale electricity provision [4]. The curve, fig. 4, for it is included for completeness but it is not a valid representation of pumped storage costs. This neglects the additional income pumped storage makes from reversing their operation to provide storage.

The availability factor of pumped storage can be reduced by weather patterns in a similar manner to wind turbines. During droughts the use of pumped storage will be limited and flooding may force reservoirs to be drained whether the turbines are running or not.

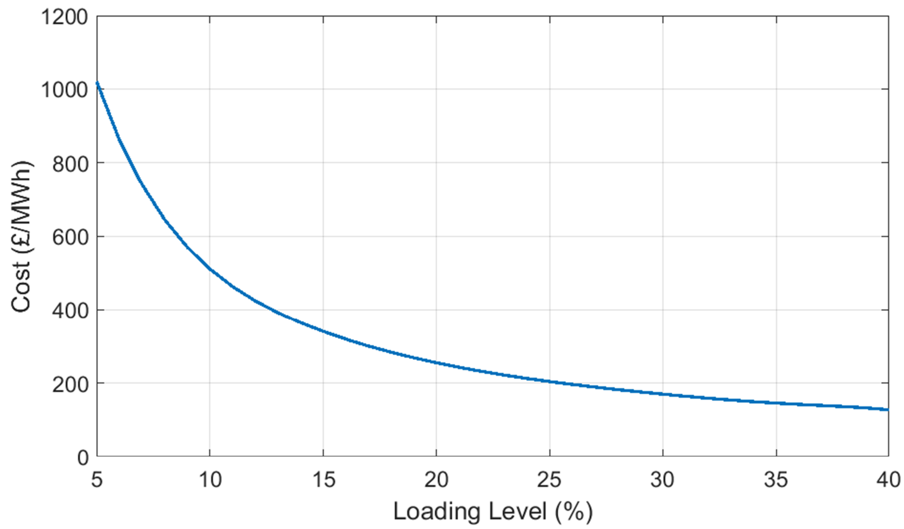

Figure 4: Change in the cost of operation of pumped storage as the average loading level varies [34]

2.3. Change over time

The change in generation mix over time has no direct impact on the cost generators must charge to recoup their investment, but will limit which generators are available for part loading. Fig. 5 shows the change in generation output between Jan 2013 and December 2017.

Coal is the cheapest part loading option and was the highest contributor to generation until the start of 2015, when most plants closed due to the LCPD [46], over 30% of the total generation supplied. CCGTs, the second cheapest part loading option, replaced coal and rose above 50% supplied generation at the end of 2016. As the two cheapest generation types to part load, with relatively similar £/MWh payback required, exchanged the dominant generation posistion the system cost of frequency response was not significantly affected.

Pumped storage is a minor contributor overall but provides additional services essential to maintaining stable operation. Wind and nuclear have much higher part loading costs, but their contributions to total generation are still far

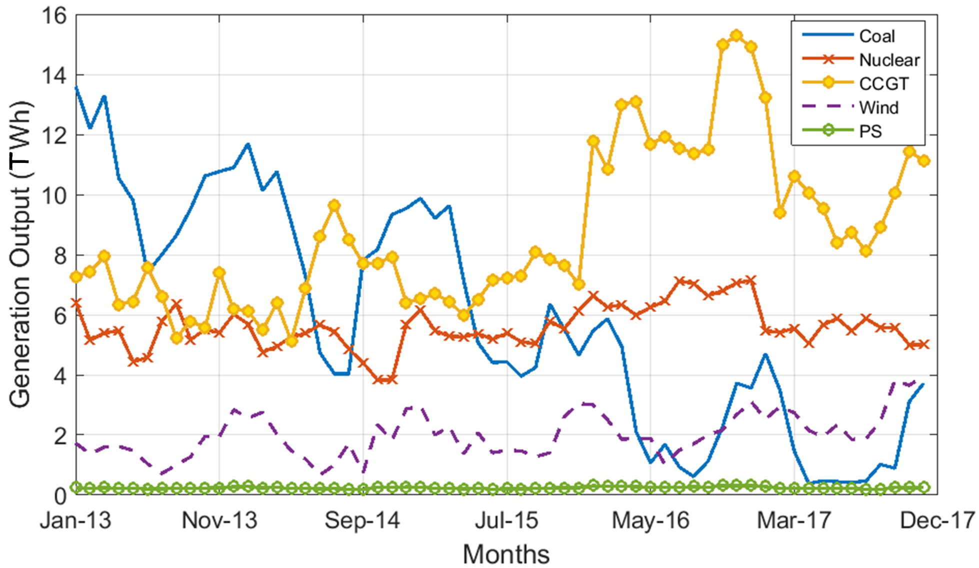

Figure 5: Change in generation output in the UK, 2013 to 2017 [48]

below that of CCGTs so are unlikely to be chosen for part loading often. This is demonstrated in section 4 with an analysis of the total system costs during 2016 and 2020 Future Energy Scenarios [2].

3. Holding payment

Part loaded generators can recoup their costs through increasing their wholesale electricity price or the provision of ancillary services. This section considers a particular ancillary service, frequency response.

3.1. Frequency response requirements

Frequency response ensures a short term balance between supply and demand, contracting generators to run in a frequency sensitive mode [49] providing some or all of the following services:

- Primary - increase in output to stabilise a drop in frequency in 10 seconds

- Secondary - increase in output to return frequency to the nominal value in 30 seconds
- High - decrease in output to return frequency to the nominal value

When considering large generators providing a response to a drop in frequency (primary or secondary) the generator must have at least 10% head room available to raise their output [49]. Likewise, for high frequency response the generator must be able to reduce their output by 10%. All large generators (except power park modules below 50MW, derogations or in operation prior to privatisation) must be capable of operating in a frequency sensitive mode which is detailed in Balancing Code no. 3 [49] and generators are paid a holding fee for operating in this mode with a response payment for any output adjustments which occur.

3.2. Generation loading levels

For stable operation generators have a DMOL, which varies from plant to plant, below which they are unable or unwilling to run for extended periods of time. These levels for different generator types are shown in table 1 [1, 24, 42].

Pumped storage is atypical in considering minimum operating levels due to their capability to charge or discharge. Technically the DMOL will be a negative value during normal operation, but it will change in relation to the reservoir levels, so is not included in table 1.

3.3. Mandatory holding payments

Each large generator submits monthly holding prices and capabilities for primary, secondary and high responses which are publically available from National Grid [4]. Using this information typical holding prices from different generator types can be calculated and are shown in table 2.

Those generators connected with low bid prices are prioritised to operate in a frequency sensitive mode and these payments are intended to reimburse generators for their loss of income. For primary and secondary frequency response

Table 2: Mandatory Frequency Response prices [4]

Generation type	Primary (£/MWh)	Secondary (£/MWh)	High (£/MWh)
Coal	3.76	1.99	6.08
CCGT	3.59	2.19	5.86
Nuclear (PWR)	25.6	43.2	42.65
Wind	10 (new)	10 (new)	25 (new)
	790 (old)	784 (old)	629 (old)
Pumped Storage	5.01	3.13	8.96

a significant component of this loss of income is from part loading the generator (a maximum output of 90% rated capacity).

As stated previously there are many other services generators may provide, rather than frequency response, causing them to raise their price above other participants. Certain generators, nuclear and old wind farms, are trying to avoid operating in frequency sensitive mode whilst others, coal and CCGTs, are aiming to be selected.

3.4. Comparison of holding payment and part loading cost

As the frequency response holding cost must reimburse generators for frequency response provision, the costs to generators from reducing loading levels for the provision of frequency response must be compared. Table 3 quantifies the cost to generators from a 10% change around their average loading level alongside the frequency payment.

In 2013 the average loading levels for coal-fired power stations were much higher, 85-90%, making the frequency response payment a more appropriate value than it initially appears.

CCGTs are often used as responsive generators, meaning they are regularly deloaded for frequency response provision already, so a payment of £5.78/MWh to cover a cost of £5.50/MWh is a suitable market price.

Table 3: Cost difference between average loading levels [4, 49]

Generation type	Cost (£/MWh) Loading Level 90-100%	Loading Level (%)	Cost (£/MWh)	Loading Level (%)	Cost (£/MWh)	Frequency Payment (£/MWh)
Coal	5.19	48-58	19.00	58-68	16.50	5.75
CCGT	3.41	62-72	8.20	72-82	5.50	5.78
Nuclear (PWR)	14.09	46-56	37.00	56-66	25.00	68.80
Wind (onshore)	6.98	18-28	60.00	28-38	25.00	20.00
Wind (offshore)	12.84	28-38	45.00	38-48	30.00	20.00
Pumped Storage	5.71	31-41	43.00	41-51	25.00	8.14

The payment for nuclear shown in table 3 is based on a PWR and it is clear from the £68.8/MWh price it is unlikely to be chosen for frequency provision. As previously explained the cost values relate to AGR designs, which are exempted from frequency response provision, but the difference in costs between reactor types is minor. The use of nuclear beyond the UK and international cost considerations imply it is an expensive and uncommon part loading option [34, 50].

Wind farms have traditionally not been used to provide ancillary services, especially type 1 and 2 turbines which set their frequency response payments high enough to remain unrequested. Type 3 and 4 turbines have set much lower prices but they do not cover the costs found in this economic assessment.

Pumped storage are willing to operate in the frequency response market but prioritise alternate balancing markets, short term operating reserve in particular, which explains their choice in raising their frequency payment above coal and CCGTs. Although this payment is insufficient to cover the cost around the typical loading level there are additional payments pumped storage plants will receive.

4. System cost

The previous sections have focused on the costs to individual generator types. The implications of these costs to the system must be considered to demonstrate their importance when scheduling generators.

4.1. 2016 - Winter peak and Summer trough

The generation supplied split between different generator types in the UK for 2016 [48] are used to demonstrate the effect loading levels have on the system costs. Table 4 contains the generation type breakdown for the Winter peak (the highest demand point in the year recorded on the 18th January at 17:30) and the Summer trough (the lowest demand point in the year recorded on the 8th August at 02:00). Unfortunately onshore and offshore wind are combined and biomass is potentially included within coal or other generation.

Table 4: Winter peak and Summer trough generation mix output in 2016 (MW) [48]

	Coal	CCGT	Nuclear	Wind	Hydro	Biomass	Solar	Interconnector
Winter	14656	21861	7791	494	2532	0	1990	2348
Summer	738	4980	7774	3837	167	120	0	16

Standard generator sizes [43], the DMOLs recorded in table 1 and total number of generators available are used to find the minimum and maximum number of generators of each type connected to the system, shown as phase 1 in fig. 8. The average loading levels and total cost for each generation type are shown in table 5 with the cost values for offshore wind used for all wind generators, resulting in an overestimate of the total system costs.

Considering the previous and post demand will be lower for the Winter peak the generators must decrease their output before and after the scenario, so the generators connected will be closer to the minimum value. The Summer trough is a reflection of the Winter peak, with the previous and post time periods having a higher demand level. As can be seen in table 5 the difference in cost for the maximum and minimum is approximately £24,000 in Winter and £400

Table 5: Average loading levels and costs with minimum and maximum generator numbers

		Coal	CCGT	Nuclear	Wind	Hydro	Biomass	Sum
Winter	%	96.2	60.4	86.7	5	52.7	0	
max	£	40433	56338	37698	2468	29418	0	166356
Winter	%	96.2	98.4	99.1	79.7	92.3	0	
min	£	40433	33119	37630	2443	28704	0	142330
Summer	%	38.8	39.2	86.5	21	3.5	33.3	
max	£	2054	12874	37617	19130	2000	232	73906
Summer	%	38.8	98	98.9	99	24.3	100	
min	£	2054	12763	37549	18924	1974	229	73494

in Summer. The significant difference between the prices in Winter is due to the number of generators varying considerably between the minimum and maximum in Winter whilst Summer has a relatively consistent number.

These minimum and maximum generation mixes ignore the requirement for low and high frequency reserves. Equation 3 quantifies the reserve requirements and limits whilst equation 4 is the cost for reserves to be minimised, with the results shown in table 6.

$$\begin{aligned} R_{req} &= \sum_{i=1}^{n} R_{gen,i} \\ 0 \leq R_{gen,i} &\leq R_{max,i} \\ 0 \leq R_{gen,i} &\leq R_{ramp,i} \end{aligned} \tag{3}$$

where R_{req} is the reserve required, R_{gen} is the reserve for each generation type, R_{max} is the maximum reserve available for each generation type and R_{ramp} is the ramp rate limit for reserve for each generation type.

$$C_{res} = \sum_{i=1}^{n} R_{gen,i} C_{gen,i} \tag{4}$$

where C_{res} is the total cost of reserves to be minimised and C_{gen} is the cost of reserves for each generation type.

In the current system reserve limits are set to 650MW high reserve and 1200MW low reserve based on the largest potential, single contingency event [51] but this will increase to 1800MW low reserve with the future connection of new nuclear generators [47]. The optimisation allocated 650MW high reserve, with the breakdown for each scenario shown in fig. 6, and 1800MW low reserve, with the breakdown shown in fig. 7. Costs for these reserve levels are shown in table 6.

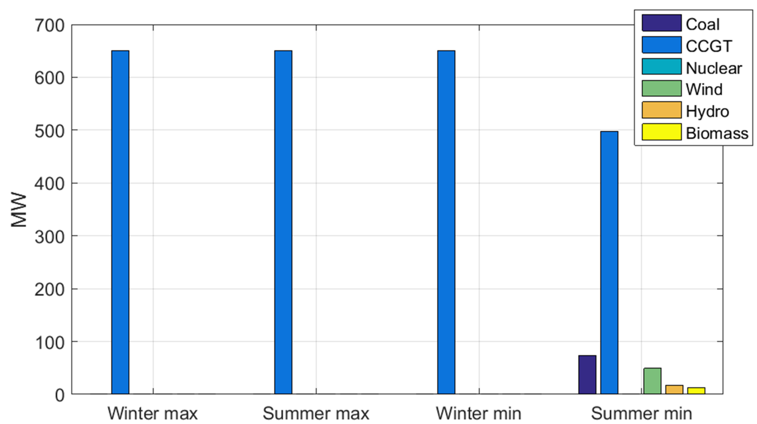

Figure 6: High reserves [4]

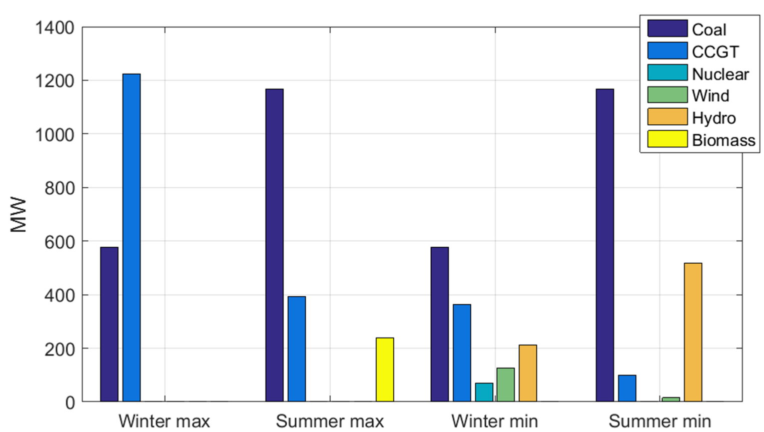

Figure 7: Low reserves [4]

Table 6: Reserve levels and costs with minimum and maximum generator numbers [4]

		Winter max	Winter min	Summer max	Summer min
High	MW	650	650	650	650
	£	3812	3812	3812	4821
Low	MW	1800	1348	1800	1800
	£	10390	14480	10368	11810
Sum	£	14203	18293	14180	16632

High reserve is exclusively provided by CCGTs, except during Summer with the minimum number of generators where it is shared between all connected generators excluding nuclear. 1800MW low reserve is provided in all scenarios, except the minimum generators in Winter where only 1348MW can be allocated between the available generators. This is still above the 1200MW required in the current system and is the only scenario utilising nuclear response. The reserve costs with more generators are consistently cheaper than those with minimum generator values, even with the shortfall in provision during the Winter peak, opposing the trend seen with the generation output.

Figure 8 explains the process of reaching an optimisation between generation output and reserves with the results shown in table 7.

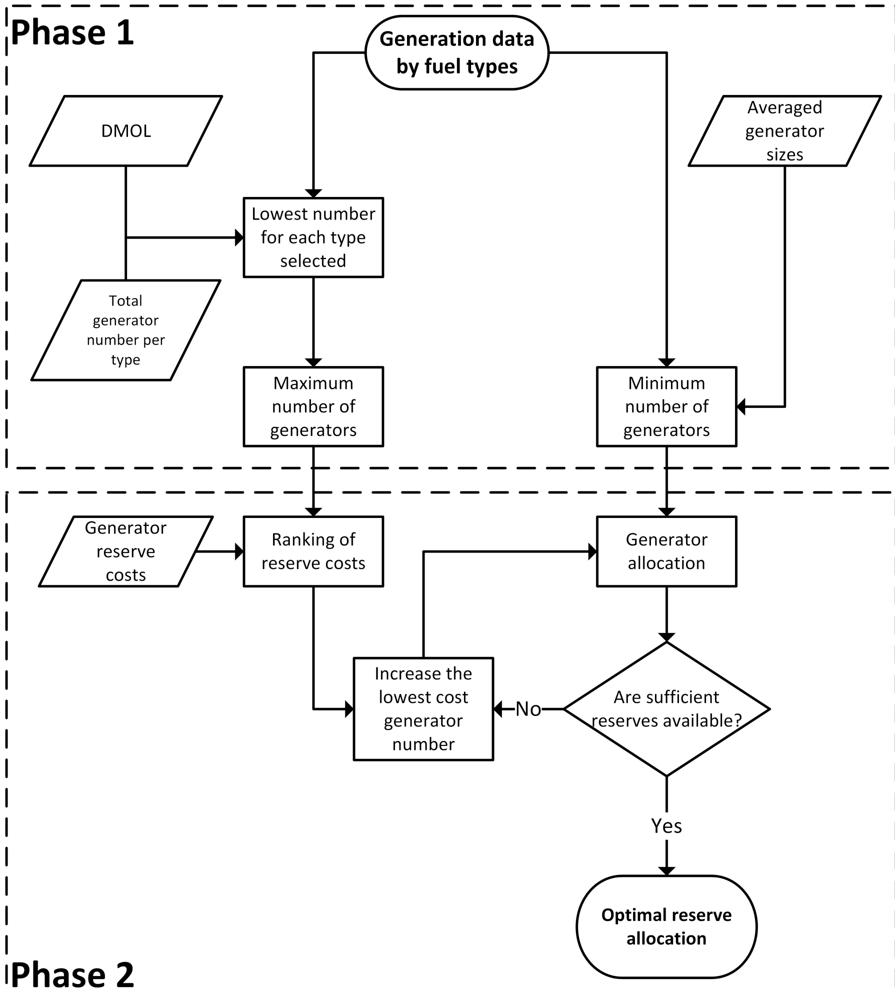

Figure 8: Flowchart of generation and reserve optimisation

Utilising the maximum and minimum generator numbers from phase 1 as inputs to phase 2 the optimal generation allocation is achieved. As shown in fig. 8 the generators connected are increased from the minimum number of generators until the reserve requirements are reached. This is done by one generator at a time, prioritising the generator with the lowest reserve provision cost available.

Table 7: Optimised loading levels and costs

		Coal	CCGT	Nuclear	Wind	Hydro	Biomass	Sum
Winter	%	96.2	93.0	99.1	79.7	92.3	0.0	
	£	40433	56069	37630	2443	28704	0	165280
High	MW	0	650	0	0	0	0	650
	£	0	3812	0	0	0	0	3812
Low	MW	576	1224	0	0	0	0	1800
	£	3314	7076	0	0	0	0	10390
Sum	£	43748	66958	37630	2443	28704	0	179482
Summer	%	38.8	39.2	98.9	99.0	24.3	100	
	£	2054	12874	37549	18924	1974	229	73605
High	MW	0	650	0	0	0	0	650
	£	0	3812	0	0	0	0	3812
Low	MW	1166	394	0	0	0	240	1800
	£	6709	2278	0	0	0	1953	10368
Sum	£	8763	18964	37549	18924	1974	2182	87785

These optimisations indicate reserves account for only 8% in the Winter peak and 16% in the Summer trough of the overall system cost. Alternative choices for reserve provision significantly increased this cost, as shown by the minimum generator costs in table 6. In contrast the overprovision of reserves by part loading generators unnecessarily, as seen in the maximum generator option in table 5, increases the generation cost whilst minimising the reserve cost.

4.2. 2020 - Winter peak and Summer trough scenarios

To assess how these costs may change in the future system the Future Energy Scenarios created by the National Grid [2] are considered. They provide details of the generation mix capacities connected each year until 2050 under four scenarios: Two Degrees involves large scale investment in low carbon technologies to meet the two degree target, Slow Progression is a gradual move towards renewable technology with limited investment, Steady State is a continuation of the current system and Consumer Power is a drive towards consumers investing in embedded generation and electric cars.

Using unit commitment by dynamic programming and average hours of daylight the generation output for the Winter peak and Summer trough in 2020 for each Future Energy Scenario is calculated, as shown in table 8. Due to the difficultly of running unit commitment on the full system each generation type is considered as a single unit.

Table 8: Winter peak and Summer trough generation mix output 2020 scenarios [2]

		Coal	CCGT	Nuclear	Wind	Hydro	Biomass	Solar	Interconnector
Two	Winter	2278	16705	8974	26123	2684	48	2182	2806
Degrees	Summer	2278	2460	4563	9505	435	48	0	3206
Slow	Winter	3272	14741	8974	25867	2374	48	2118	2806
Progress	Summer	3048	2261	4178	8769	402	48	0	3206
Steady	Winter	7422	14691	8974	23565	2366	48	1989	2246
State	Summer	3216	2390	4427	9245	421	48	0	2565
Consumer	Winter	3749	15845	8974	25192	2548	48	2338	2806
Power	Summer	3124	2320	4291	8985	411	48	0	3206

As with the 2016 generation mixes, minimum and maximum number of generators connected were considered with the results shown in tables 9 and 10. Reflecting the results seen in table 5 the saving in cost for minimising generators connected is typically in the order of hundreds of pounds.

Table 9: Total system costs for generation with minimum and maximum generator numbers

	Two degrees		Slow progress		Steady state		Consumer power	
	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer
Max £	252835	87446	245769	83141	245642	87759	248537	85222
Min £	251717	84850	244830	82423	244705	86953	247479	84480

Table 10: Reserve costs with minimum and maximum generator numbers

			Two degrees		Slow progress		Steady state		Consumer power	
			Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer
Max	High	£	3812	3812	3812	3812	3812	3812	3812	3812
	Low	£	10404	10404	10404	10398	10404	10357	10404	10387
Min	High	£	3812	6446	3812	5420	3812	4837	3812	5157
	Low	£	3446	77404	6310	28553	6664	12417	1890	21451

All scenarios with the maximum number of generators connected cover the reserve requirements of 650MW high reserve and 1800MW low reserve provided by coal, CCGT and biomass. However the minimum number of connected generators are unable to meet the low response requirements for all scenarios. Despite failing to provide sufficient low response the Summer scenarios with minimum generators are consistently more expensive whilst Winter scenarios with minimum generators are only cheaper if the value of lost load, the potential result from insufficient reserves, is ignored.

Table 11: Optimised loading levels and costs totals for all 2020 FES

		Two degrees		Slow progress		Steady state		Consumer power	
		Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer
Output	£	251778	86753	244871	82448	244746	86991	247479	84506
High	£	3812	3812	3812	3812	3812	3812	3812	3812
Low	£	10404	10404	3299	3316	3299	10357	3299	10387
Sum	£	265994	100969	251982	89577	251857	101161	254591	98706

The optimised total costs for generation output and reserve are provided in table 11, which indicates the significant spread in costs between the different scenarios. As can be seen in table 8 the scenarios correspond to diverse demand levels and their generation mixes vary considerably making direct comparisons between the scenarios impossible. However the percentage of the total cost attributable to reserves can be considered in comparison with those seen in

2016. Reserves are provided by coal, CCGT and biomass, as seen before in 2016, whilst other generators maintain their minimum numbers of connected generators.

Winter scenarios vary between 2.8% and 5.3% of the total cost from reserves, compared with 8% seen in 2016, whilst this percentage rises to between 8% and 14.4% in the Summer, 16% in 2016. As can be seen in table 11 this is caused by both the reserve cost being either equal or higher during the Summer whilst the generator output costs decrease.

Overall the scenarios demonstrate a system wide cost saving can be achieved by ensuring part loading is prioritised for coal and CCGTs, whilst ensuring other generators maintain high loading levels when operating.

5. Conclusion

The variation in costs seen by generators as their average loading level changes shows there are substantial differences between the generation types. Coal and combined cycle gas turbine (CCGT) generators can be deloaded to approximately 80% without experiencing significant increases in cost whilst nuclear and wind see a much steeper immediate rise. Pumped storage is also considered but the difference in capability and participation in alternate balancing services make it an unfair comparison. System wide costs for 2016 and 2020 scenarios shows a difference in generation cost of up to £24,026 due to the part loading of generators. Through optimising reserve provision and minimising unnecessary part loading a significant reduction in the total system cost, up to £2,341 per half hour time period, can be achieved. The variation in cost of part loading different generator types demonstrates the importance of a wide portfolio. This ensures those capable of providing balancing services in an economic manner are available whilst generators more suited to base load operation can run with a steady output at a high loading level.

Acknowledgements

The authors would like to thank several members of the UK electricity industry for their assistance and Horizon Nuclear Power for their support in this project.

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